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**PROJECT NO. 52373**

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| **REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN** | **§ § §** | **BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS** |

**RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC.'S COMMENTS ON THE COMMISSION'S OCTOBER 25, 2021 QUESTIONS**

Rayburn Country Electric Cooperative, Inc. ("Rayburn") files these Comments regarding the Public Utility Commission of Texas's ("Commission") October 25, 2021 Questions for Comment - Project No. 52373 (the "October 25 Memo").

## Background

Rayburn is a Texas-based not-for-profit generation and transmission electric cooperative that, through its four members,[1] provides power to approximately 225,000 consumers — of which about 90% are residential consumers — in Northeast Texas. Rayburn and its members are the sole providers of electricity to those consumers.

Rayburn's mission is to obtain, generate and transmit reliable and affordable energy to its members, that in turn deliver power to end-users. Rayburn obtains power from various sources to maintain lower power costs for its members, including through bi-lateral power purchase agreements from power suppliers, approximately 250 MW from the 1,000 MW Freestone Energy center, approximately 60 MW from the 80 MW U.S Army Corps of Engineers Denison Hydroelectric Station, short-term bi-lateral hedges, renewables and purchases from the ERCOT market. Rayburn also owns and operates over 290 miles of transmission lines in Texas located entirely within ERCOT.

[1] Rayburn's member cooperatives are Fannin County Electric Cooperative, Inc., Farmers Electric Cooperative, Inc., Grayson-Collin Electric Cooperative, Inc., and Trinity Valley Electric Cooperative.

Within the ERCOT market, Rayburn operates as a Load Serving Entity ("LSE"), a Qualified Scheduling Entity ("QSE"), a Transmission and Distribution Service Provider ("TSDP") and a Congestion Revenue Right ("CRR") Account holder.

Rayburn thanks the Commission for the opportunity to submit these written comments and participate in the Commission's review of the Texas wholesale market design. In this document, Rayburn provides comments on the topics requested by the Commission in the October 25 Memo and reserves the right to provide further comments on these and any other topics as this proceeding continues to progress.

## I. Load Serving Entity Obligation

Chairman Lake's October 20, 2021 Memo and the Commission's October 25 Memo focus on questions relating to the impact of imposing a Load Serving Entity ("LSE") Obligation in the ERCOT market. While it is hard to measure the impact of an LSE Obligation on Rayburn, its members and on ultimate end-use customers without a defined proposal to review, Rayburn urges the Commission to exercise caution before imposing an LSE Obligation. An LSE Obligation will likely lead to increased costs in the real-time energy market, and may still fail to provide the reliability and stability needed for the ERCOT grid to perform in all manners of extreme weather and periods of high demand.

An LSE Obligation outsources responsibility for the reliability of the transmission grid to LSEs, and there is no guarantee that every LSE is sufficiently sophisticated to perform that function. If an LSE fails to accurately calculate how much power it will require, successfully contract for its full requirements, or negotiate sufficiently stiff penalties for a failure to perform by the generator or its fuel supplier, it may not be able to meet this obligation.

Further, if the LSE Obligations are met solely or primarily through bilateral contracting with unrelated generators that is out of sight of the Commission and ERCOT, and where parties have little information about what is being offered to others, there may be significant potential for gaming and other unfavorable outcomes from pressured negotiations in a "forced purchase" regime for capacity. Furthermore, an LSE may face substantial risks associated with the contractual obligations including performance requirements. If the Commission moves forward with an LSE Obligation, there must be sufficient oversight to ensure that the failure of one or more LSEs to meet their obligation cannot destabilize the grid. However, LSEs that meet their obligation to procure resources should not be penalized if the resources they procure fail to meet their contractual obligations to the LSE. And the Commission should continue to pursue other measures for increasing grid reliability, such as weatherization and generator operational reliability.

## II. Response to Specific Commission Questions

**Question 1: The ORDC is currently a "blended curve" based on prior Commission action. Should the ORDC be separated into separate seasonal curves again? How would this change affect operational and financial outcomes?**

Rayburn believes that the most important change to the ORDC is to reduce the PUCT's administratively approved high system-wide offer cap ("HCAP") from its current level of $9,000 per MWh to $4,500 per MWh as urged by Texas Senate Resolution 342[2] to ameliorate the future risk of excessively high electricity prices to consumers and as was proposed by the October 7, 2021 amendment to 16 TAC § 25.505(g)(6)(B).[3] Senate Resolution 342 expressed concern

[2] S. R. No. 342, 87th Leg. (2021).

[3] *See* PUCT Project No. 52631.

regarding the "massive electricity bills" many Texas residents faced in the wake of Winter Storm Uri.[4]

Regarding shifting to seasonal ORDC curves, an approach that ERCOT moved away from in 2019,[5] a theoretical potential improvement exists if seasonal ORDC curves are adopted, though how much of an impact this would have on market reliability as a whole is hard to predict. Further, caution is needed in interpreting seasonal historical performance and loss of load probabilities from past events with regard to such performance reflecting unduly high generator outages that arose from failure to properly weatherize and maintain reliable power generation supply, as seen during Winter Storm Uri.

**Question 2: What modifications could be made to existing ancillary services to better reflect seasonal variability?**

There is insufficient information to discern any needed modifications to ERCOT's existing ancillary services as these already incorporate monthly minimum requirements for the existing ancillary service products offered.

**Question 3: Should ERCOT develop a discrete fuel-specific reliability product for winter? If so, please describe the attributes of such a product, including procurement and verification processes.**

**a. How long would it take to develop such a product?**

**b. Could a similar fuel-based capability be captured by modifying existing ancillary services in the ERCOT market?**

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[4] The Resolution also noted that ERCOT's HCAP, which is the highest in the nation (having nearly tripled between 2012 and 2015) and threatens utilities and retail electric providers, which collectively face billions of dollars in charges related to the blackout. *Id.*

[5] Electric Reliability Council of Texas (2021), http://www.ercot.com/mktrules/issues/OBDRR011#keydocs.

The most important winter season modification is to ensure weatherization of power generators in ERCOT. Some of these measures are being put in place from the ERCOT Weatherization Rule Approved October 21, 2021.[6] Further attention could be given to ensure adequate dual fuel capable generation capacity and ensuring both fuel sources are reliable. However, it is unclear whether a fuel specific reliability product would result in additional reliability beyond the level achieved by weatherization and other targeted reliability measures or simply add costs to consumers.

**Question 5: Are there alternatives to an LSE Obligation that could address the concerns raised about the stakeholder proposals submitted to the Commission?**

All measures that improve grid reliability should be considered. The gross damage wrought by Winter Storm Uri was largely caused by the failure of power generation resources to perform as well as the gas supply market. The biggest electricity market issue was that so many generators were out of service, not that the LSEs had failed to arrange for sufficient capacity. The problem with an LSE Obligation is that even if penalties are put in place for generation failing to show up, that alone does not bring certainty and stability to the grid. A penalty may not be enough to inspire a generator to comply with its requirements — generators may choose to pay a penalty rather than putting power online in certain circumstances and if the gas supply market fails again, may be unable to perform. This creates a cascading effect that is not just bad for the LSE, but brings instability to the ERCOT grid.

**Question 6: How can an LSE Obligation be designed to protect against the abuse of market power in the wholesale and retail markets?**

**a. Will an LSE Obligation negatively impact customer choice for consumers in the competitive retail electric market in ERCOT? Can protective measures be**

[6] *See* Order Adopting New 16 TAC § 25.55 As Approved at the October 21, 2021 Open Meeting, Project No. 51840 (October 25, 2021).

**put in place to avoid a negative impact on customer choice? If so, please specify what measures.**

b. **How can market power be effectively monitored in a market where owners of power generation also own REPs that serve a large portion of ERCOT's retail customers?**

c. **What is the impact on self-supplying large industrial consumers who will have to comply with the LSE Obligation and will it impact their decision to site in Texas?**

d. **What is the impact of an LSE Obligation on load-serving entities that do not offer retail choice, such as municipally owned utilities or electric cooperatives?**

e. **Can market power be monitored in the bilateral market if an LSE Obligation is implemented in ERCOT? Can protective measures be put in place to ensure that market power is effectively monitored in ERCOT with an LSE Obligation? If so, please specify what measures.**

f. **Should the LSE Obligation include a "must offer" provision? If so, how should it be structured?**

With respect to Question 6(d), the impact of an LSE Obligation on load-serving entities that do not offer retail choice, Rayburn cannot speak for all such entities, it can only offer its own perspective. The parameters set forth for the LSE Obligation need to be better defined for Rayburn to be certain, but as set forth in the Appendix, they appear to be somewhat similar to Rayburn's current power procurement practices. So although Rayburn likely will need to make a few adjustments, based on the information provided so far, it does not anticipate that the proposed LSE Obligation would have a significant negative impact on Rayburn related to Rayburn's NOIE status.

With respect to Question 6(e), significant challenges exist with respect to an LSE Obligation as discussed in Section I as well as Rayburn's responses to Questions 15 and 16.

**Question 7: How should an LSE Obligation be accurately and fairly determined for each LSE? What is the appropriate segment of time for each obligation? (Months? Weeks? 24 hour operating day? 12 hour segments? Hourly?)**

With regard to the time periods discussed, at most an LSE Obligation should apply for capacity to meet a level of reserves required for an annual or seasonal period. More discrete LSE

obligations over the hours of the day, weeks or months of the year increase risks and burdens to LSEs as well as increased administrative burdens and other challenges. Other ISOs with similar capacity requirements to an LSE Obligation, such as SPP, only utilize a seasonal resource adequacy requirement and do not consider a daily, weekly or monthly obligation.

**Question 9: How can the LSE Obligation be designed to ensure demand response resources can participate fully and at all points in time?**

To the extent that an LSE or the LSE's contracting party has irrevocable, functional control over the demand response resources, such as the ability to remotely control thermostats or reduce other types of load, such resources could be considered eligible resources for meeting the LSE Obligation. However, to the extent that customers retain the ability to decide whether or not to respond to the call for demand response, such resources should not be relied upon to meet the LSE Obligation.

**Question 10: How will an LSE Obligation incent investment in existing and new dispatchable generation?**

An LSE Obligation would only incent investment in new dispatchable generating resources that meet the requirements of the rule, and only to the extent that such resources are not currently present in the market. Investment in new generation, however, is not as critical as ensuring that all dispatchable and non-dispatchable generation, whether new or existing, is reliable and performs when needed. Furthermore, an LSE Obligation without a complementary revenue stream for building reliable generation is unlikely to increase grid stability given the costs associated with such investment decisions.

**Question 11: How will an LSE Obligation help ERCOT ensure operational reliability in the real-time market (e.g., during cold weather events or periods of time with higher than expected electricity demand and/or lower than expected generation output of all types)?**

As described above, even the most well-designed LSE Obligation would likely not independently ensure operational reliability in the real-time market. Financial penalties alone

cannot force generators to bring power online during severe weather events or during periods of higher than expected demand. Indeed, neither prior guidance to properly weatherize power generators as a lesson learned from the 2011 winter storm or very high $9000/MWH prices during February 2021 ameliorated the impacts to consumers who face "massive electricity bills" from Winter Storm Uri.

**Question 13: What is the estimated market and consumer cost impact if an LSE obligation is implemented in ERCOT? Describe the methodology used to reach the dollar amount.**

While the cost will be impacted by a host of factors yet to be determined, as is explained in more detail below, in California, for the first ten years of California's purchase obligation, the average contract price over a ten year period was approximately $8-$41/MWH higher than market prices (about 45% higher).

**Question 14: How long will the LSE Obligation plan take to implement?**

The LSE Obligation should be phased in over a long enough period to ensure that it does not create a market distortion driven by a rush to market.

**Question 15: If the Commission adopts an LSE Obligation, what assurances are necessary to ensure transparency and promote stability within retail and wholesale electric markets?**

There is a significant risk that an LSE Obligation that pushes the vast majority of purchases out of the market and into bilateral contracting out of sight of the Commission and ERCOT would create opportunities for gaming and other unfavorable outcomes from pressured negotiations in a "forced purchase" regime for capacity. Furthermore, an LSE may face substantial risks associated with the contractual obligations including performance requirements. The Commission should also consider how to ensure that LSEs negotiate sufficient contract penalties with generators to ensure that generators meet their contract obligations to the LSE.

**Question 16: Are there relevant "lessons learned" from the implementation of an LSE Obligation in the SPP, CAL-ISO, MISO, and Australian markets that could be applied in ERCOT?**

If the Commission adopts an LSE Obligation for the ERCOT real-time energy market, it should implement the obligation in a phased approach. If an LSE Obligation is not phased in over time, there is near certainty that the rush of parties to the market to enter into new contracts would cause a market distortion that would cause market participants to overpay for power. The California ISO faced an energy crisis during the 2000-2001 period with very high prices, outages and claims of market design failures of the newly formed wholesale power market that led to major electric utilities in bankruptcy. With the goal to help secure future electricity supplies and stabilize wholesale prices, in 2001 the California government (specifically the Department of Water Resources) entered into long-term power contracts with unregulated generators.[7] In April 2001, the California Department of Water Resource ("CDWR") provided a presentation that summarized its power purchase contract efforts.[8] The CDWR presentation describes the ten-year average contract price as $71/MWH over 2001 through 2010 with an average contract price of $86/MWH for 2001 through 2005 and $60/MWH for 2006 through 2010.[9] Indeed, the actual market prices were much lower than the prior contracted prices. Specifically, annual average wholesale power

[7] Congressional Budget Office, Congress of the United States, Cause and Lesson of the California Electricity Crisis, September 2001, page xi-xii, https://www.cbo.gov/sites/default/files/107th-congress-2001-2002/reports/californiaenergy.pdf.

[8] California Department of Water Resources, Summary of California Department of Water Resources Power Purchase Contract Efforts, April 18, 2001. (As Exhibit 37 In Public Utilities Commission of the State of California v. Allegheny Energy Supply Company, LLC, et al, Section 206 Compliant, FERC Docket No. EL02-60-000, Volume 1, February 25, 2002, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20020225-0159).

[9] *Id.* at 2 and 11.

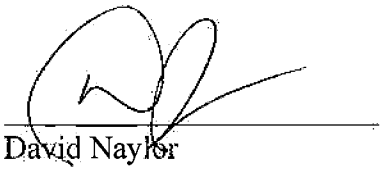
prices (and costs) were in the $45-$57/MWH range during the 2002-2005 period[10] and in the $40-$50/MWH range from 2006-2010.[11]

## Conclusion

Rayburn thanks the Commission and Staff for the opportunity to provide comments in the above captioned docket. As noted in these comments, Rayburn continues to support market design changes that increase the reliability of the grid and looks forward to continued participation in the Commission's market design project.

Dated: November 1, 2021

Respectfully submitted,



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[10] California ISO, 2006 Market Issues and Performance Annual Report, at 2-35, http://www.caiso.com/Documents/2006AnnualReportonMarketIssuesandPerformance.pdf.

[11] California ISO, 2010 Market Issues and Performance Annual Report, at 3, http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

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## RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC.'S EXECUTIVE SUMMARY OF COMMENTS

In proposing a market design blueprint, Rayburn recommends that:

- The Commission exercise caution in developing an LSE Obligation, because it is likely to lead to increased costs in the market, and, standing alone, may not be enough to produce grid stability;
- Changing the ORDC to reduce the $9000 HCAP to $4500 is most important, however, there is a potential for improvement in grid reliability through the adoption of seasonal ORDC curves;
- The most important winter season modification is to ensure weatherization of generators in ERCOT;
- All measures that improve grid reliability should be considered, the gross damage wrought by Winter Storm Uri was largely caused by the failure of power generation resources to perform as well as the gas supply market;
- Based on information currently available, the proposed LSE Obligation would be sufficiently similar to Rayburn's current power procurement practices that Rayburn would not expect to have a significant negative impact on Rayburn related to Rayburn's NOIE status;
- An LSE Obligation at most should apply for capacity to meet a level of reserves required for an annual or seasonal period, consistent with practices in other markets;
- If a utility has functional control of demand response resources, they should be allowed to count toward an LSE Obligation, however, demand response resources where the customer retains the ability to decide not to participate should not be permitted to count toward an LSE Obligation;
- An LSE Obligation without a complementary revenue stream for building dispatchable resources is unlikely to increase grid stability, given the costs associated with such investment decisions;
- Even the most well-designed LSE Obligation would not independently ensure operational reliability in the real-time market. Neither the prior guidance to

weatherize generators after the 2011 storm event, nor the $9000 HCAP price during the Winter Storm Uri event were sufficient to prevent impacts to customers who face massive electricity bills from Winter Storm Uri;

- In the first 10 years of the California purchase obligation, the average contract price year was approximately 45% higher than market prices;

- The LSE Obligation should be phased in over a long-enough period of time to ensure that it does not create a market distortion caused by a rush to market; and

- An LSE Obligation that pushes the vast majority of purchases out of the sight of ERCOT and the Commission would create opportunities for gaming and other unfavorable outcomes from pressured negotiations.